Integration Cost Adder Status Report

Teleconference for Parties to the LTPP (R.13-12-010)
and RPS (R.15-02-020) Proceedings:

January 12, 2016 9:30am – 11:30am

California Public Utilities Commission, Energy Division

Teleconference Logistics

Call-in: 866-830-2902
Passcode: 2453758

- Upon entry to the call, place yourself on mute (*6 to mute/unmute)
- Remain on mute unless you are actively asking a question. Please mute yourself when done speaking.
- Announce your name and organization before speaking

Agenda

- Introduction (Energy Division) [9:30]
- Background and Production Cost Simulation Overview (E3) [9:35]
- Technical Challenges and Potential Solutions (SCE) [10:10]
- Next Steps (E3) [10:50]
- Q&A (All) [11:00]

Introduction to Integration Adder Project

- A March 27, 2015 ALJ Ruling in the LTPP proceeding (R.13-12-010) directed Southern California Edison (SCE) to perform modeling for the purposes of calculating integration cost adders for use in RPS procurement Least-cost, Best-fit (LCBF) evaluation and the RPS Calculator

- On May 29, 2015, SCE submitted interim modeling results for the 33% RPS cases that were later called into question due to newly discovered modeling flaws

- On December 15, 2015, SCE filed a Progress Report describing the modeling issues that have arisen from work to calculate the integration cost adder

- The purpose of this teleconference is to discuss the progress and challenges of the renewable integration cost adder analysis described in the Progress Report

Background and Production Cost Simulation Overview

Arne Olson, Partner
Nick Schlag, Managing Consultant

Overview

- **Quantifying the costs of renewable integration is necessary to inform both procurement (LCBF) and planning (RPS Calculator)**
  - AB 2362 requires Commission to approve a methodology for determining the integration costs by December 31, 2015
  - Integration costs include "expenses resulting from integrating and operating eligible renewable energy resources, including, but not limited to, any additional wholesale energy and capacity costs associated with integrating each eligible renewable resource."
- **In D.14-11-042, CPUC adopted "interim" renewable integration cost adders for wind and solar PV**
  - Variable cost components based on literature review ($4/MWh for wind; $3/MWh for solar PV)
  - Fixed cost component based on price of flexible RA and three-hour net load ramps

Net Market Value Calculation in RPS Calculator and LCBF

- **Framework used to develop order of resources in the supply curve closely mirrors Net Market Value calculation used in LCBF**
  - Intended to capture all cost impacts on utility ratepayers
- **Net resource cost is calculated for all possible generic resources in the model to enable the choice of the least cost resources for the portfolio**

RPS Calculator Valuation Framework

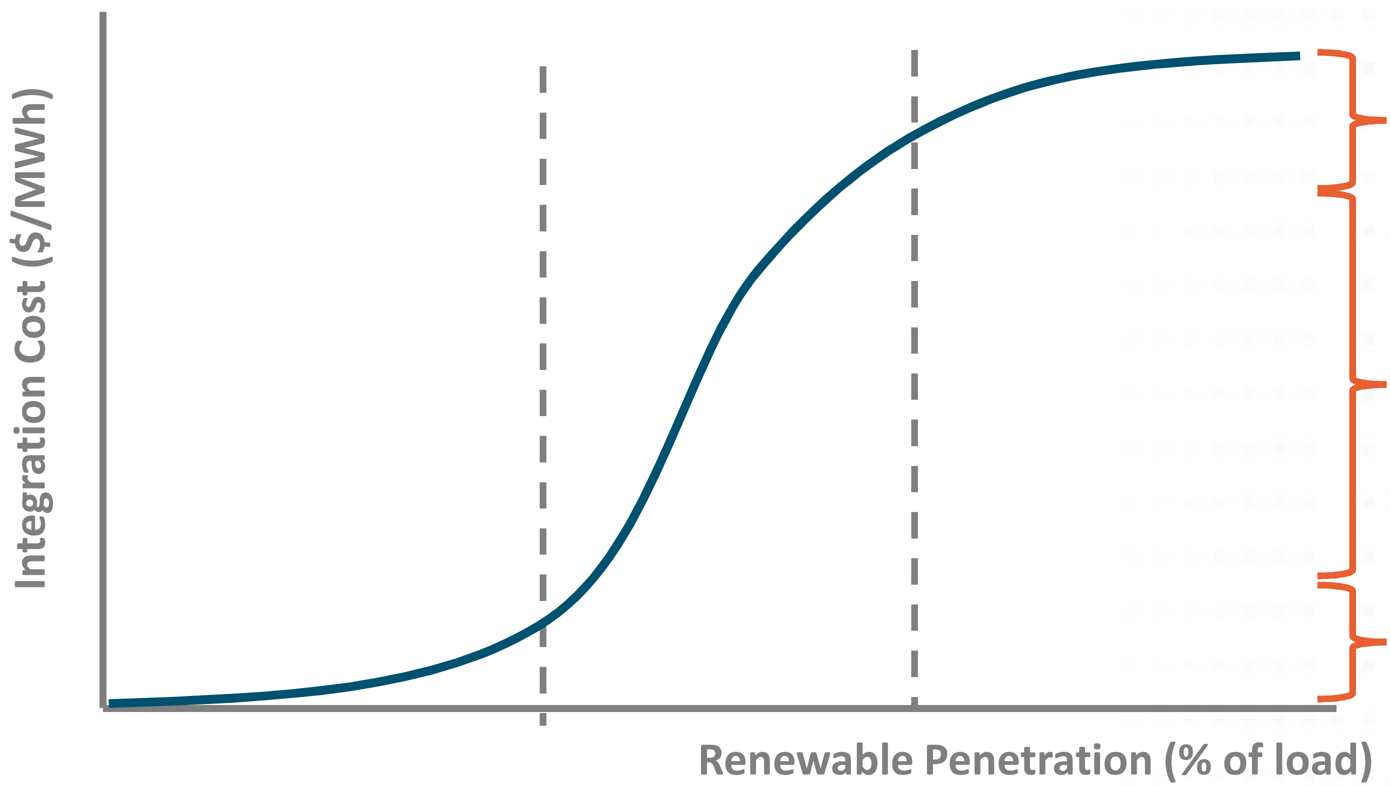
+	Levelized Cost of Energy
+	Transmission Cost
−	Capacity Value
−	Energy Value
+	Curtailment Cost
+	Integration Cost
=	Net Resource Cost

Conceptual Renewable Integration Cost Curve

Low Penetration:
Operating costs only (increased Regulation and Load Following)

Medium Penetration:
Flexibility constraints lead to curtailment and need to invest in flexible capacity

High Penetration:
Storage or other integration technology required to accompany renewables



Fixed Costs:
Investment in flexibility solutions becomes cost-effective

Curtailment Costs:
Oversupply and flexibility-related renewable curtailment

Variable Costs:
Reduced gas plant efficiency due to increase in operating reserves

Integration Cost Adder captures flexibility-related costs only

- **Cost categories not yet quantified include operating reserves and dispatch inflexibility**
  - Residual integration adder addressed in E3/SCE effort much smaller than other categories
- **Many effects related to “saturation” already captured in RPS Calculator**
  - Declining marginal capacity value with penetration → estimates of marginal Effective Load Carrying Capability
  - Declining dispatch savings with penetration → analysis of changing marginal dispatch costs
  - Curtailment of renewables due to oversupply → hourly comparison of expected renewable production profiles with load plus export capability

Variable Integration Cost Evaluation Framework

- **Variable integration costs defined as costs resulting from…**
  - …the need to carry additional reserves (regulation & load following) to compensate for forecast error and intra-hour variability
  - …the need to meet increased inter-hour ramps
- **These factors drive a need for flexibility in operations, which results increases in cost due to the impacts on:**
  - Unit commitment decisions
  - Dispatch of committed generators
- **Use standard model without modification**
  - CAISO's 2024 LTPP PLEXOS case is the de facto standard

For a given renewable portfolio:

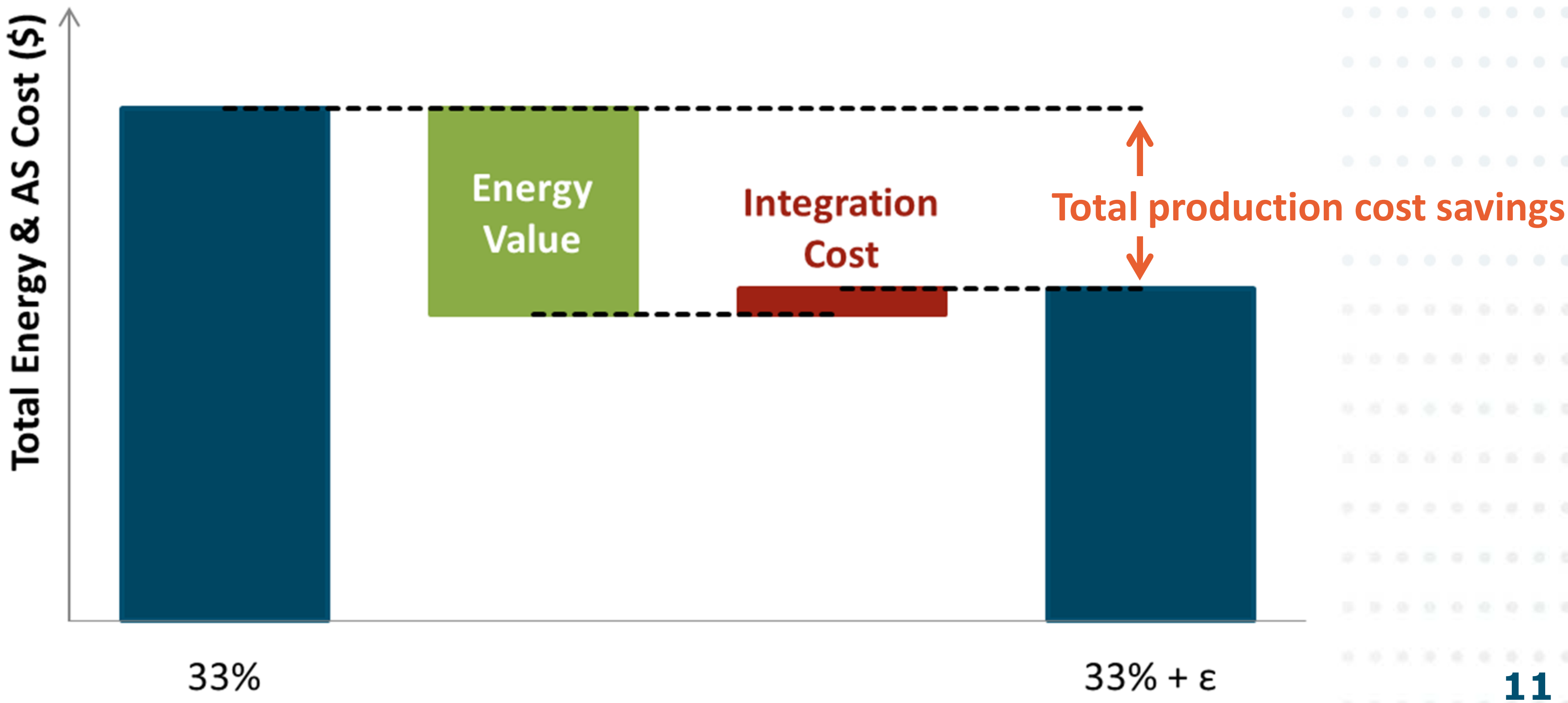
Operating Costs **Ignoring** Flexibility-Related Constraints

Cost Δ = "Integration Cost"

Operating Costs **Accounting for** Flexibility-Related Constraints

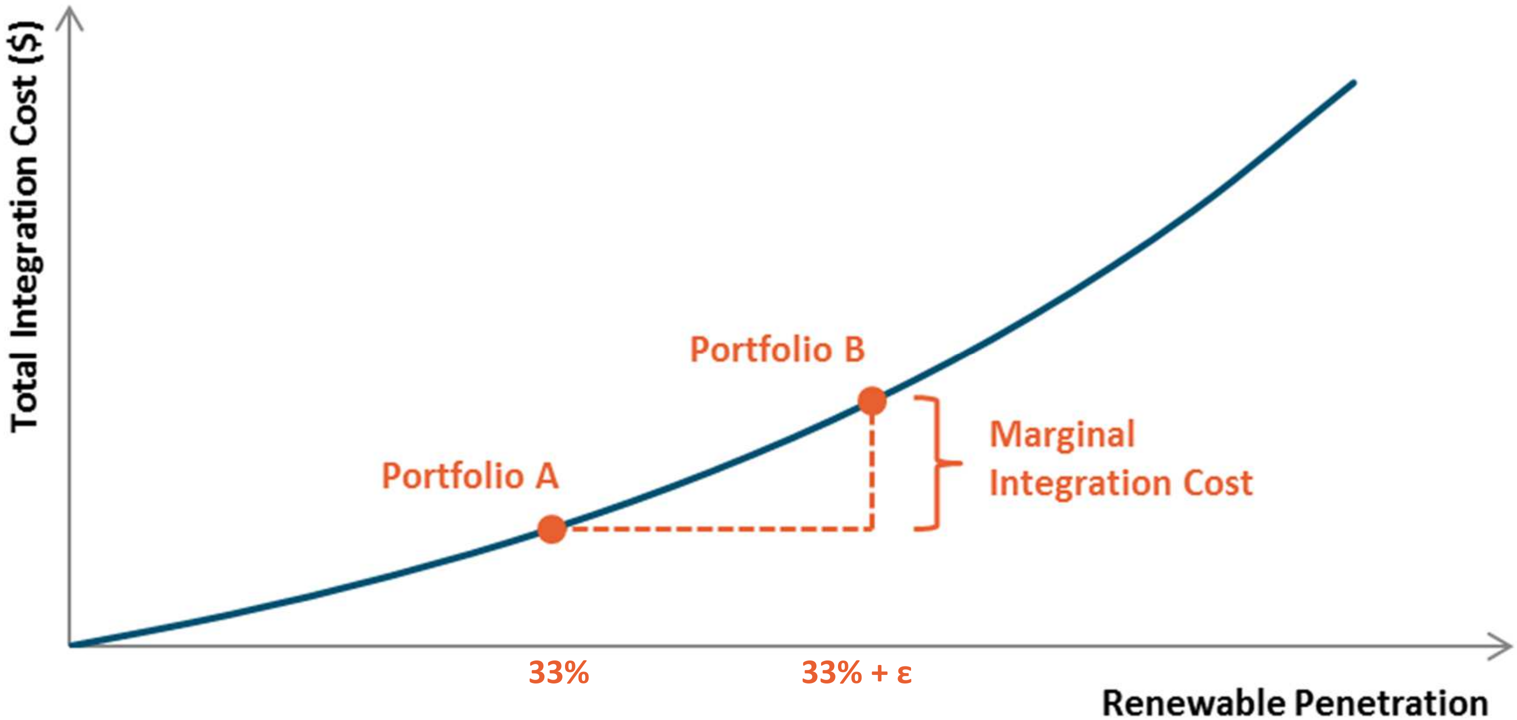
Energy Value & Integration Cost

- **Both "energy value" and "integration cost" capture some impact adding renewables upon the cost of operating the electric system**
- **These two components are shown independently in Net Market Value formulation but they are actually very closely linked**
  - The method for determining integration cost depends how energy value is calculated
  - RPS Calculator uses a "stack" model that ignores most dispatch constraints
  - More sophisticated methods might already capture some or all of the integration costs



Marginal Integration Costs

- Analysis is focused on characterizing the marginal integration cost at any given market penetration



- Currently focused on marginal integration costs between 33% and 40% RPS

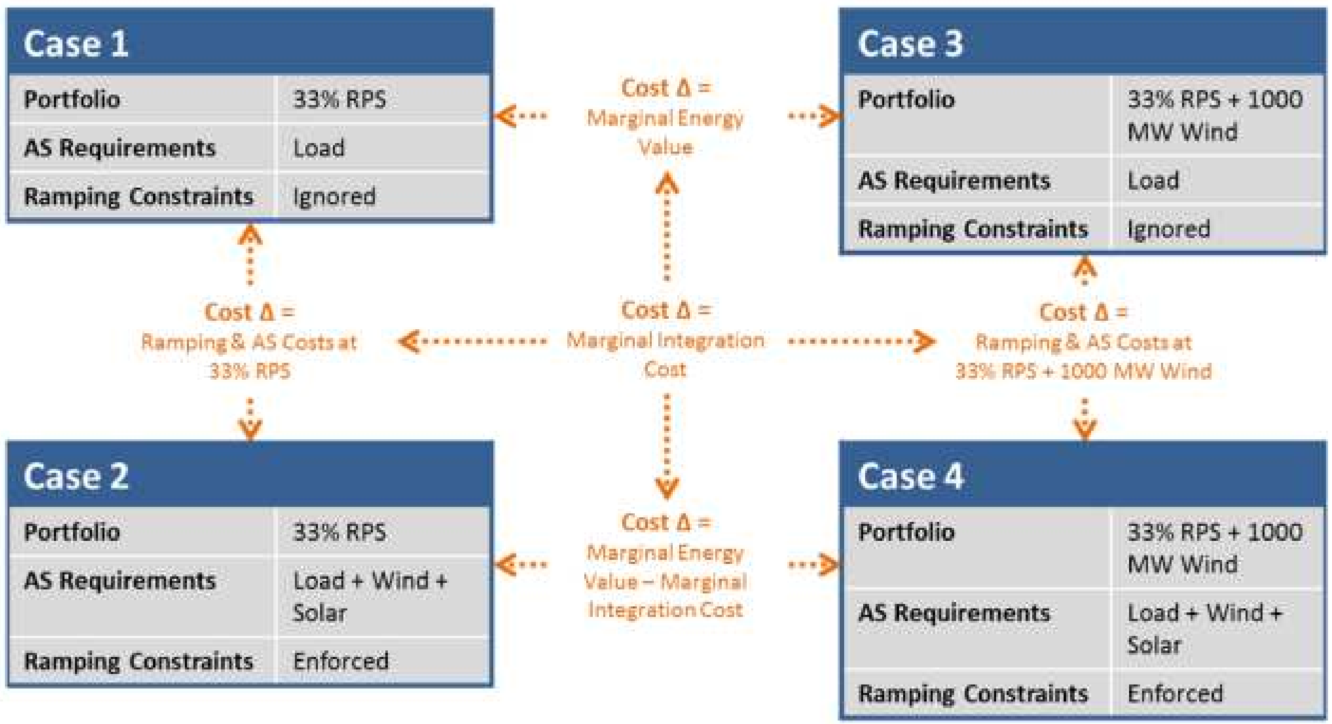
Methodology Overview

+ **The costs associated with the need for operational flexibility can be determined through multiple production simulation runs**

Figure 1. Illustrative use of four production simulation cases to calculate marginal integration cost for a specific resource type.

"Flexibility Unconstrained"

"Flexibility Constrained"



CAISO Production Simulation Model

- **2024 case developed by CAISO and Energy Exemplar using PLEXOS for Power Systems**
  - Zonal, WECC-wide production simulation model with features that are desirable for calculating flexibility costs
    - Integer variables for unit commitment decisions
    - Co-optimization of energy & ancillary services
- **PLEXOS optimizes the dispatch of the Western Interconnection system by minimizing dispatch costs over successive 24-hour periods**

Key Production Simulation Definitions (1)

- **Production simulation models are optimization models that seek to minimize an <u>objective function</u> subject to a variety of <u>constraints</u>**
- **<u>Objective function</u>**
  - Sum of <u>all costs</u> to be minimized, which includes all operational costs (e.g. fuel, variable O&M, and start costs) as well as some non-operational costs (e.g. wheeling costs, penalty costs associated with renewable curtailment, reserve shortages)
- **<u>Hard constraints</u>**
  - Constraints that cannot be violated in the simulation
- **<u>Soft constraints</u>**
  - Constraints that may be violated but violations are discouraged by applying a **<u>penalty cost</u>** to them in the objective function (e.g. reserve requirement constraints, which may be violated at a $/MWh cost penalty)

Key Production Simulation Definitions (2)

- **How does a production simulation model find the optimal solution?**
  - Algorithm searches across possible solutions for the lowest cost solution
  - When the numerical solution is sufficiently close to the true optimal solution, the algorithm quits searching and the problem is said to have **converged**
- **MIP gap**
  - In a Mixed Integer Programming optimization problem, such as the PLEXOS model, the tolerance threshold that must be met for the model to converge is called the **MIP gap**
  - A smaller MIP gap will increase the precision of the solution (i.e. ensure that it is closer to optimal), but may increase the time required to converge

TECHNICAL CHALLENGES AND PROPOSED SOLUTIONS (SCE)

Status Update

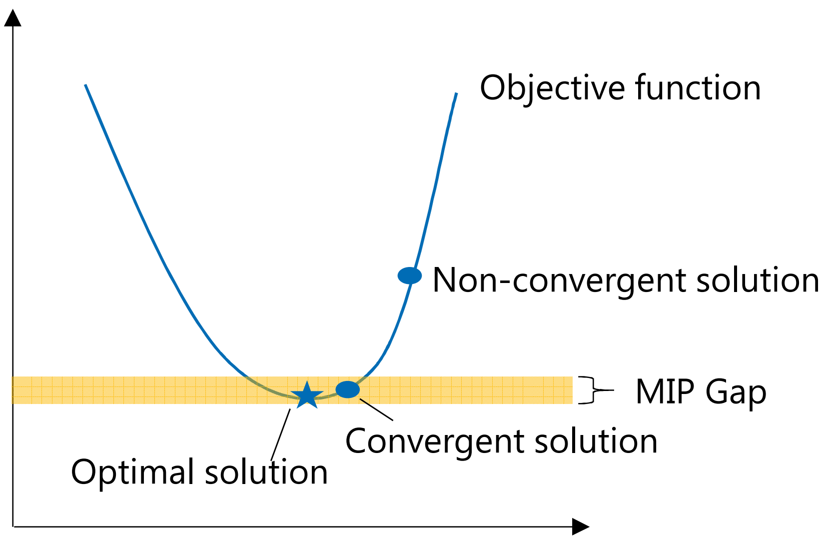
The model runs have yet to reach a viable solution

- The technical issues identified are:
  1. Non-convergence
  2. Unstable objective function
  3. Non-economic penalty prices over-impacting results
- The potential solutions explored are:
  1. Adjust curtailment methodology
  2. Modify penalty prices
  3. Add generic flexible capacity
  4. Change soft constraints into hard constraints
  5. Permit net exports from California

Technical Issue: Non-Convergence

- Non-convergence occurs in many days and in varying frequencies across the cases
  - The high frequency of non-convergence across the cases is unreasonable
  - Cases have different frequencies of non-convergence, making it difficult to assess the impact of incremental renewables in a differences of differences methodology

Illustrative Example



Model Convergence Criteria

	MIP Gap	Time Limit (seconds)
33% RPS Cases (1-6)	0.20%	4,000
40% RPS Cases (7-12)	0.10%	4,000

Technical Issue: Large Swings in Objective Function

- Large swings in the objective function were identified and may be a cause of non-convergence
- Generally, the objective function is negative
  - Renewable curtailment is modeled as a variable operation & maintenance (VOM) cost of **-**$300/MWh, which makes the objective function negative
- However, penalty prices can cause the objective function to be positive
  - For example, reserve shortfall is modeled with a penalty cost of $750,000/MWh
  - Cases have different frequencies of reserve shortfall, making it difficult to assess the impact of incremental renewables in a differences of differences methodology
- These swings from a negative to a positive objective function represent a potential cause in non-convergence as it may cause the model to require more time to solve

Technical Issue: Non-Economic Penalty Costs

- Penalty costs are used to help the model prioritize system operations; therefore, they do not always reflect economic costs
  - These penalty costs may have played a large role in the overall objective function, making it difficult to compare cases to find the impact of incremental renewables
- Sample costs from the model:

Constraint	Penalty Cost
Exceed monthly demand response dispatch limits	$2,000,000/MWh-month
Exceed monthly hydro dispatch limits	$1,000,005,000/MWh-month
Local generation requirement not met	$10,000/MWh
Load following up shortfall	$750,000/MWh
Non-spin shortfall	$775,000/MWh

Potential Solution: Adjust Curtailment Methodology

Technical Issues Addressed:

Non-convergence	*Swings in objective function*	*Non-economic penalty prices*

- Objective:
  - Eliminate frequency of negative objective functions
- Method:
  - Change renewable VOM to $0/MWh
  - Impose cost for over-generation rather than using negative VOM cost

Potential Solution: Modify Penalty Prices

Technical Issues Addressed:

Non-convergence	*Swings in objective function*	*Non-economic penalty prices*

- Objective:
  - Minimize the impact of large, artificial penalty prices on the objective function and differences between cases
- Method:
  - Replace artificial penalty costs with economic costs

Constraint	Artificial Cost	Economic cost*
Unserved Energy	$3.2MM/MWh	$50,000/MWh
Load Following Up shortfall	$750,000/MWh	$12,500/MWh
Over-generation	-$300/MWh	-$100/MWh
Load Following Down shortfall	$7,000 MWh	-$25/MWh

** Economic cost values provided by E3*

Potential Solution: Add Generic Flexible Capacity

Technical Issues Addressed:

Non-convergence	*Swings in objective function*	*Non-economic penalty prices*

- Objective:
  - Eliminate all instances of energy or reserve shortfall to avoid differences in cases are caused by shortfall costs
- Method:
  - Add a sufficient amount of generic flexible capacity to meet energy and reserve requirements in all cases
  - Use generic capacity with properties similar to an LMS 100 for modeling purposes only

Potential Solution: Change Soft Constraints into Hard Constraints

Technical Issues Addressed:

Non-convergence	*Swings in objective function*	*Non-economic penalty prices*

- Objective:
  - Eliminate impact of artificial penalty prices that vary across cases
- Method:
  - Require the model to solve within the constraint where possible
- Example:
  - Soft constraint: Monthly demand response dispatch limits can be surpassed at the cost of $2 million for each additional MWh of demand response beyond the limits
  - Hard constraint: Monthly demand response dispatch limits cannot be exceeded, and therefore do not incur additional costs

Potential Solution: Permit Net Exports from California

Technical Issues Addressed:

Non-convergence	*Swings in objective function*	*Non-economic penalty prices*

- Objective:
  - Minimize the frequency of large swings in the objective functions caused by renewable curtailment
- Method:
  - Allow the modeled California electricity market to export power to the rest of WECC to reduce curtailment

NEXT STEPS

Next Steps

+ **Previous test runs have not resulted in satisfactory formulation**
  - Goal is to develop "well-behaved" production simulation model cases:
    - Convergence criteria are met; model results are not unduly influenced by arbitrary penalty values; results are intuitive
    - This is also important for future uses of CAISO's PLEXOS model
  - Latest test runs of single months showed significant improvement but did not entirely eliminate influence of load following penalties
+ **Final test runs currently in production**
  - Testing will include multiple months
  - Testing will include 40% RPS cases
+ **Team still evaluating options for final integration adders**
  - Recommendations & direction taken depend on results of final test runs

Procedural Next Steps

- The Dec 8, 2015 ALJ Ruling in the LTPP proceeding set forth milestones assuming no further difficulties:
  - SCE submits complete report with 33% and 40% RPS analysis and results by Mar 4, 2016
  - Workshop presenting results by Mar 18, 2016
  - Party opening comments due April 1, 2016
  - Party reply comments due April 8, 2016
  - Proposed Decision in summer 2016
- Items will be filed and served in this LTPP proceeding or its successor, and the RPS proceeding